

**BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2010-3-E**

In the Matter of
Annual Review of Base Rates
for Fuel Costs for
Duke Energy Carolinas, LLC

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**DIRECT TESTIMONY OF
JOHN J. ROEBEL FOR DUKE ENERGY
CAROLINAS, LLC**

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION**
2 **WITH DUKE ENERGY CAROLINAS.**

3 A. My name is John J. Roebel and my business address is 139 E. Fourth Street,
4 Cincinnati, Ohio 45202. I am employed by Duke Energy Business Services, LLC as
5 Senior Vice President of Generation Support, and am an officer of Duke Energy
6 Carolinas, LLC (“Duke Energy Carolinas” or “the Company”).

7 **Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS SENIOR VICE**
8 **PRESIDENT OF GENERATION SUPPORT?**

9 A. I lead the group responsible for business management and planning, metrics and
10 measurement, investment engineering, project controls, and information technology
11 strategy for the Company’s generation organization.

12 **Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND**
13 **PROFESSIONAL BACKGROUND.**

14 A. I received a bachelor’s degree in mechanical engineering from the University of
15 Cincinnati Engineering College in 1980. Since that time I have completed graduate
16 courses, primarily in business administration, from both the University of Cincinnati
17 and Xavier University.

18 I worked for The Cincinnati Gas & Electric Company (“CG&E”) as a co-op
19 student in the engineering area during undergraduate school, and became a full-time
20 employee after graduation in 1980. Since joining CG&E, and later Cinergy
21 Services, Inc. after the merger of PSI Energy, Inc. (“PSI”) and CG&E, I have held a
22 number of positions of increasing responsibility in the engineering and construction
23 management areas. Some of those positions include mechanical project engineer for

1 a new coal-fired unit, project manager on the conversion of CG&E's Zimmer station
2 from nuclear to coal, as well as leading the design and construction of CG&E's
3 Woodsdale Generating Station. Beginning in April 2006, I served as Senior Vice
4 President, Engineering and Technical Services until being named to my present
5 position in October 2009.

6 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
7 **PROCEEDING?**

8 A. The purpose of my testimony is to discuss the performance of Duke Energy
9 Carolinas' fossil-fueled and hydroelectric generating facilities during the review
10 period of June 2009 through May 2010 (the "review period"). I discuss the impact
11 of planned outages experienced in the Carolinas on the fossil and hydroelectric
12 generation fleet and the status of construction and operation of environmental
13 controls equipment at coal-fired stations. In addition, I address certain variable
14 environmental costs that are included in the proposed fuel factor.

15 **Q. PLEASE DESCRIBE DUKE ENERGY CAROLINAS' FOSSIL AND**
16 **HYDROELECTRIC GENERATION PORTFOLIO.**

17 A. Duke Energy Carolinas' fossil/hydro generation portfolio consists of approximately
18 13,900 megawatts ("MW") of generating capacity, made up as follows:

19 Coal-fired generation - 7,654 MWs

20 Hydroelectric - 3,156 MWs

21 Combustion Turbines - 3,120 MWs

22 (Combustion turbines can operate on natural gas or fuel oil)

1 This portfolio includes a diverse mix of units that, along with additional nuclear
2 capacity, allow the Company to meet the continuously changing customer load
3 pattern in a logical and cost-effective manner. The cost and operational
4 characteristics of each unit generally determine the type of customer load situation
5 that the unit would be called upon to support. Base load units typically have lower
6 operating costs but higher initial capital costs to install than other generating units.
7 These larger units are called upon first to support customer load requirements and,
8 thus, run almost continuously. In addition to Duke Energy Carolinas' seven nuclear
9 units, the seven largest coal-fired units often operate under these base load
10 conditions. Intermediate units are dispatched next to support customer demand,
11 ramping up and down throughout each day to match load requirements as they
12 change. These units take time to ramp up from a cold shut down and are best used
13 to respond to more predictable system load patterns. This intermediate fleet is made
14 up of thirteen coal-fired units. During periods of highest customer demand, many of
15 these intermediate units will also operate at maximum capacity and almost
16 continuously along with the base load units discussed above.

17 Peaking units typically have higher operating costs but relatively lower
18 initial capital costs to install than base load or intermediate units. They have the
19 ability to be started quickly in response to a sharp increase in customer demand,
20 without having to operate continuously. These peaking units are called upon when
21 customer demand is high and thus typically have lower capacity factors than the
22 base load or intermediate units. The remaining ten small coal units as well as the
23 entire hydroelectric fleet and entire gas/oil-fired combustion turbine fleet make up

1 this peaking category. The Company's hydroelectric and combustion turbine units
2 are especially good for supporting abrupt changes in load demand as their generation
3 output can usually ramp up or down very quickly.

4 Company witness Pitesa will discuss the nuclear fleet in his testimony.

5 **Q. PLEASE EXPLAIN THE BENEFITS OF THE COMPANY'S DIVERSE MIX**
6 **OF GENERATING UNITS.**

7 A. Operating a generating fleet with a great amount of diversity of fuel and operating
8 characteristics, combined with purchased power and demand-side options, provides
9 the Company with opportunity to meet all load demand scenarios in the most cost-
10 effective manner. Based on the load demand that the Company is called upon to
11 serve at any given point in time, operators select the combination of generating unit
12 and purchased power options that will produce electricity in the most economical
13 manner with consideration for issues such as reliability of service, environmental
14 compliance, and safety. This cost-optimization approach to system operations
15 allows for the minimization of the total cost of providing electric service to
16 customers.

17 **Q. HOW DOES THE COMPANY DECIDE WHEN TO OPERATE EACH**
18 **TYPE OF GENERATING UNIT?**

19 A. Each day, Duke Energy Carolinas selects the combination of Company-owned
20 generating units and available power purchases that will most reliably meet
21 customer needs in a least-cost manner. Available units with the lowest operating
22 costs (fuel, emission allowances, and variable operating and maintenance costs, etc.)

1 are dispatched first, with higher cost units added as load increases. Intraday
2 adjustments are made to reflect changing conditions and purchase opportunities.

3 **Q. PLEASE DESCRIBE HOW PURCHASES OF POWER FROM OTHER**
4 **SUPPLIERS FIT INTO THIS PROCESS.**

5 A. The Company monitors the energy market, evaluating long-term, seasonal, monthly,
6 weekly, daily, and hourly purchase opportunities. In making these daily decisions of
7 which resources should be used to meet customer needs, the Company may purchase
8 energy from other suppliers, whether under existing long-term capacity agreements
9 or short-term spot market purchases, to ensure it selects the most cost-effective and
10 reliable solution.

11 **Q. WHAT CHANGES TO THE FOSSIL/HYDRO GENERATION PORTFOLIO**
12 **CAPACITY HAVE BEEN MADE DURING THE REVIEW PERIOD?**

13 A. In 2009, the coal fleet capacity decreased by 18 MW at the Allen Steam Station as a
14 result of the installation of the flue gas desulfurization (“FGD” or “Scrubber”)
15 equipment for sulfur dioxide (“SO₂”) emissions reduction. There was also a 2 MW
16 de-rate for combustion turbines at Lee to adjust to the officially rated capacity to
17 match the output guaranteed by the supplier. In the spring 2010 review of available
18 system capacity, the peaking combustion turbine capacity decreased by 20 MW for
19 Buzzard Roost. These turbines were installed in the late 1960s and are approaching
20 end of life, with increasing difficulty in finding parts required for optimal operation.
21 In addition, the hydro fleet capacity decreased by approximately 60 MW. A portion
22 of the decrease is due to excess hydraulic capacity (25 MW) while the remaining
23 decrease is the result of necessary repairs for various units.

1 **Q. WHAT ARE THE COMPANY’S OBJECTIVES IN THE OPERATION OF**
2 **ITS FOSSIL AND HYDROELECTRIC GENERATING UNITS?**

3 A. The primary objective of Duke Energy Carolinas’ fossil/hydro generation personnel
4 is to safely provide reliable and cost-effective electricity to the Company’s South
5 Carolina and North Carolina customers in compliance with all applicable
6 environmental regulations. This objective is achieved through the Company’s focus
7 on a number of key areas. Operations personnel and other station employees are
8 well-trained and execute their responsibilities to the highest standards, in accordance
9 with procedures, guidelines, and a standard operating model. Duke Energy
10 Carolinas achieves compliance with all applicable environmental regulations and
11 maintains station equipment and systems in a cost-effective manner to ensure
12 reliability. The Company also takes action in a timely manner to implement work
13 plans and projects that enhance the performance of systems, equipment, and
14 personnel, consistent with providing low-cost power options for the Company’s
15 customers. Equipment inspection and maintenance outages are executed with
16 quality, are well-planned, and are scheduled when appropriate, with the primary
17 purpose being to prepare the plant for reliable operation until the next planned
18 outage.

19 **Q. WHAT HAS BEEN THE HEAT RATE OF DUKE ENERGY CAROLINAS’**
20 **COAL UNITS DURING THE REVIEW PERIOD?**

21 A. Heat rate is a measure of the amount of thermal energy needed to generate a given
22 amount of electric energy and is expressed as British thermal units (“BTU”) per
23 kilowatt-hour (“kWh”). Over the review period, the average heat rate for the coal

1 fleet was 9,622 BTU/kWh. A low heat rate indicates an efficient fleet that uses less
2 heat energy from fuel to generate electrical energy. Duke Energy Carolinas has
3 consistently been an industry leader in achieving low heat rates. In 2008 operating
4 performance data published in the November/December 2009 issue of *Electric Light*
5 *and Power* magazine, Duke Energy Carolinas' Belews Creek Steam Station and
6 Marshall Steam Station ranked as the country's first and eighth most energy efficient
7 coal-fired generators, respectively. In this publication, the Belews Creek Steam
8 Station heat rate was calculated at 9,204 BTU/kWh, and the Marshall Steam Station
9 heat rate was calculated at 9,453 BTU/kWh. Over the review period, the Belews
10 Creek and Marshall units provided the majority (73.6%) of coal-fired generation for
11 Duke Energy Carolinas.

12 **Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DUKE ENERGY**
13 **CAROLINAS' FOSSIL GENERATING UNITS DURING THE REVIEW**
14 **PERIOD.**

15 A. Duke Energy Carolinas' coal-fired generating units operated efficiently and reliably
16 during the review period. Two key measures are used to evaluate the operational
17 performance of generating facilities: (1) equivalent availability factor and (2)
18 capacity factor. Equivalent availability factor refers to the percent of a given time
19 period a facility was available to operate at full power, if needed. Equivalent
20 availability is not affected by the manner in which the unit is dispatched or by the
21 system demands; however, it is impacted by planned and unplanned (*i.e.*, forced)
22 outage time. Capacity factor measures the generation a facility actually produces
23 against the amount of generation that theoretically could be produced in a given time

1 period, based upon its maximum dependable capacity. Capacity factor is affected by
2 the dispatch of the unit to serve customer needs. Given the different operating
3 characteristics for each generating unit, it is appropriate to evaluate these factors
4 based on the operational categories discussed previously – base load, intermediate,
5 and peaking.

6 Duke Energy Carolinas' seven base load coal units achieved results of 83.8%
7 equivalent availability factor and 70.9% capacity factor over the review period.
8 During the 2009 peak summer season (May through August 2009), these base load
9 units achieved excellent results of 89.4% equivalent availability factor and 72.5%
10 capacity factor. The Company's thirteen intermediate coal units achieved results of
11 93.4% equivalent availability factor and 36.0% capacity factor over the review
12 period, and performed similarly during the 2009 summer peak months at 94.0%
13 equivalent availability and a capacity factor of 31.0%. Duke Energy Carolinas' ten
14 peaking coal units achieved results of 91.9% equivalent availability factor and 7.6%
15 capacity factor for the review period, and performed well during the 2009 summer
16 peak months at 97.6% equivalent availability and a capacity factor of 4.8%.

17 The capacity factor for the entire coal-fired generating fleet was 55.7% for
18 the review period and 55.0% during the 2009 summer peak months. Overall, the
19 coal units achieved a fleet-wide availability factor of 87.2% for the review period
20 and 91.4% during the 2009 summer peak months. These results compare favorably
21 with the most recently published NERC average equivalent availability results for all
22 North American coal plants of 84.7%. This NERC availability average covers the

1 period 2004-2008 and represents the performance of over 800 North American coal-
2 fired units.

3 The Company's combustion turbines were available for use as needed in this
4 time period. A key measure of success for the combustion turbine fleet is starting
5 reliability. During the twelve-month period, the large combustion turbines at the
6 Lincoln, Mill Creek, and Rockingham plants had 263 successful starts out of 264
7 requests for a 99.6% starting reliability result.

8 These results are indicative of solid performance and good operation and
9 management of Duke Energy Carolinas' fossil fleet during the review period.

10 **Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S**
11 **HYDROELECTRIC FACILITIES DURING THE REVIEW PERIOD.**

12 A. The hydroelectric fleet had outstanding operational performance during the review
13 period with an overall availability factor of 93.55%. This availability factor
14 measurement refers to the percentage of a given time period that each hydroelectric
15 unit was available to operate, if needed. This availability measure is not affected by
16 the manner in which the unit is dispatched, but is impacted by the amount of unit
17 outage time. Rainfall in the Duke Energy Carolinas service area was near long-term
18 average during this review period, resulting in typical dispatch of conventional and
19 pumped storage units for peaking demand load. There were no drought impacts to
20 hydroelectric operations during this review period.

21 **Q. PLEASE DISCUSS SIGNIFICANT PLANNED OUTAGES OCCURRING AT**
22 **DUKE ENERGY CAROLINAS FOSSIL AND HYDROELECTRIC**
23 **FACILITIES DURING THE REVIEW PERIOD.**

1 A. In general, planned maintenance outages for all fossil and larger hydroelectric units
2 are scheduled for the spring and fall to maximize unit availability during periods of
3 peak demand. Most of these units had at least one small planned outage during this
4 review period to inspect and repair critical boiler and balance of plant equipment.
5 Five of the thirty coal units had extended planned outages of three weeks or more.
6 Allen Unit 4 was scheduled for scrubber inspection and maintenance. In the fall of
7 2009, Lee Units 1 and 2 had scheduled outages for electrostatic precipitator
8 maintenance. The remaining two significant planned outages on coal-fired units
9 were required for major boiler repairs and turbine and generator overhauls (Belews
10 Creek Unit 2) and major turbine overhaul and boiler repairs (Cliffside Unit 4).

11 For the large combustion turbine fleet, Rockingham Unit 3 had a scheduled
12 outage for compressor repairs. Rockingham Unit 5 had a planned outage for a hot
13 gas path inspection and generator inspection.

14 **Q. PLEASE DISCUSS HOW THE COMPANY'S PROGRESS ON**
15 **ENVIRONMENTAL CONTROLS AND COMPLIANCE PROJECTS**
16 **IMPACTS THE AVAILABILITY OF THE FOSSIL FLEET.**

17 A. Pollution control equipment is required to reduce NO_x and SO₂ emissions in
18 accordance with federal, state, and local requirements. Selective Catalytic
19 Reduction ("SCR") or Selective Non-Catalytic Reduction ("SNCR") equipment has
20 been installed and is operational on 18 coal-fired units. Burner replacements have
21 also been installed on other peaking coal units for enhanced NO_x performance.
22 Duke Energy Carolinas has made significant progress on the installations of
23 scrubber technology in support of SO₂ emission limits. Scrubbers at Marshall,

1 Belews Creek, and Allen were placed in service prior to the review period. The
2 remaining scrubber installation at Cliffside Unit 5 is in progress and is expected to
3 be in service by the end of 2010.

4 Duke Energy Carolinas minimizes the amount of scheduled outage time
5 necessary for environmental equipment additions when possible by performing
6 multiple projects during a scheduled outage and performing as much construction
7 work as possible while the units are online. However, these mandated
8 environmental installation projects require significantly greater planned outage days
9 as compared to that typically experienced for the fossil fleet. In addition to the
10 outages necessary for installation of these environmental controls, having this
11 environmental equipment in service impacts the day-to-day operation of the fossil
12 fleet. The SCR and scrubber equipment require auxiliary power, which reduces the
13 overall output of these facilities. Retrofitting existing units to support such
14 equipment is also expected to result in balance of plant operational issues that the
15 station personnel must monitor and address as they arise.

16 **Q. PLEASE DISCUSS THE USE OF REAGENTS IN CONNECTION WITH**
17 **THE OPERATION OF ENVIRONMENTAL EQUIPMENT ADDITIONS.**

18 A. As discussed above, Duke Energy Carolinas is required to install and operate
19 pollution control equipment on its coal units in order to meet various federal, state,
20 and local reduction requirements for NO_x and SO₂ emissions. The SCR technology
21 is currently installed and operational on four coal units, and the SNCR technology is
22 currently installed and operational on 14 units for the purpose of reducing NO_x
23 emissions. The scrubber technology has been installed and is operational on 11 units

1 for the purpose of reducing SO₂ emissions with an additional installation at Cliffside
2 Unit 5 in progress. Each of these technologies requires the presence and
3 consumption of a reagent in order for the chemical reaction to occur that eliminates
4 the NO_x or SO₂ emissions. The SCR technology that the Company currently
5 operates uses ammonia or, in the case of Marshall Unit 3, urea in the presence of a
6 catalyst for NO_x removal, and the SNCR technology injects urea into the boiler for
7 NO_x removal. The scrubber technology that the Company operates uses crushed
8 limestone for SO₂ removal. Organic acid (often referred to as “DBA” or “dibasic
9 acid”) can also be used with the scrubber technology for additional SO₂ removal.

10 The quantity of reagent consumed in these emission reduction processes
11 varies depending on the generation output of the unit, the chemical constituents in
12 the coal being burned, and the level of emission reduction required. Station
13 operators must monitor each of these parameters to ensure that the equipment is
14 being operated in the most efficient and effective manner possible, optimizing
15 emission reduction goals and the overall cost effectiveness of unit operations.

16 **Q. HOW DOES THE COMPANY ENSURE THAT COSTS ASSOCIATED**
17 **WITH CONSUMING THESE REAGENTS ARE PRUDENT AND**
18 **MANAGED EFFECTIVELY?**

19 A. The Company’s objective in procurement of these environmental reagents and
20 managing these by-products is to provide the stations with the most effective total
21 cost solution for operation of the unit, understanding the technical capabilities of the
22 equipment, assessing reagent input and by-product output over the long-term,
23 assessing and understanding the various reagent and by-product markets, and

1 looking for leverage opportunities with the reagent purchase and by-product sales
2 contracts between stations and with Duke Energy Corporation's Midwest operations.

3 Technical and sourcing teams have been established to accomplish these
4 objectives for the NO_x reagents in use and for the management of gypsum and coal
5 ash by-products. These teams have addressed short-term issues associated with
6 reagent sourcing, including the review and refinement of transportation methods and
7 award of regional reagent supply contracts, and have developed strategies for the
8 long-term. Company witness Batson addresses the procurement of limestone used
9 for SO₂ removal.

10 **Q. WHAT COSTS FOR AMMONIA, UREA, AND ORGANIC ACID ARE**
11 **INCLUDED IN THE COMPANY'S PROPOSED FUEL FACTOR?**

12 A. For the review period, Duke Energy Carolinas incurred costs of \$5.4 million for
13 ammonia in operating the SCR equipment at the Belews Creek and Cliffside stations
14 and \$4.7 million for urea in operating the SNCR equipment at the Allen, Buck,
15 Marshall, and Riverbend stations and SCR equipment on Marshall Unit 3. Organic
16 acid costs were incurred only in minute amounts in operating the scrubbers at
17 Marshall. Company witness Batson discusses limestone costs in his testimony.

18 With environmental equipment additions placed in service, these reagent
19 costs are expected to increase. For the billing period of October 2010 to September
20 2011, Duke Energy Carolinas is currently projecting to consume approximately \$8.2
21 million worth of ammonia in operating the SCR equipment at the Belews Creek and
22 Cliffside stations and approximately \$5.4 million worth of urea in operating the
23 SNCR equipment at the Allen, Buck, Marshall, and Riverbend Stations and the SCR

1 equipment on Marshall Unit 3. Organic acid is not expected to be consumed in any
2 significant quantities in operating the scrubber equipment at the Marshall, Belews
3 Creek, and Allen stations over this same time period. In addition to the limestone
4 consumption discussed by Company witness Batson, the Company has included
5 \$13.6 million in estimated ammonia and urea reagent cost in calculating the variable
6 environmental component of its proposed fuel factor.

7 **Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

8 A. Yes, it does.